8 Fuel Assumptions

The EPA Base Case 2000 includes assumptions on coal, natural gas, oil, biomass and nuclear fuels. These assumptions pertain to the fuel characteristics, fuel market structure and fuel prices.

8.1 Coal

The EPA Base Case 2000 uses regional supply curves to represent the available supply of coal. Transportation costs are based on the supply infrastructure, which connects the demand and supply components of the modeled coal markets. Section 8.1.1 below contains details of the coal market assumptions in EPA Base Case 2000.

The EPA Base Case 2000 also includes coal quality assumptions which differentiate coal by rank (i.e, bituminous, subbituminous, and lignite) and sulfur and mercury content. Section 8.1.2 below describes the coal quality assumptions in EPA Base Case 2000.

8.1.1 Coal Markets

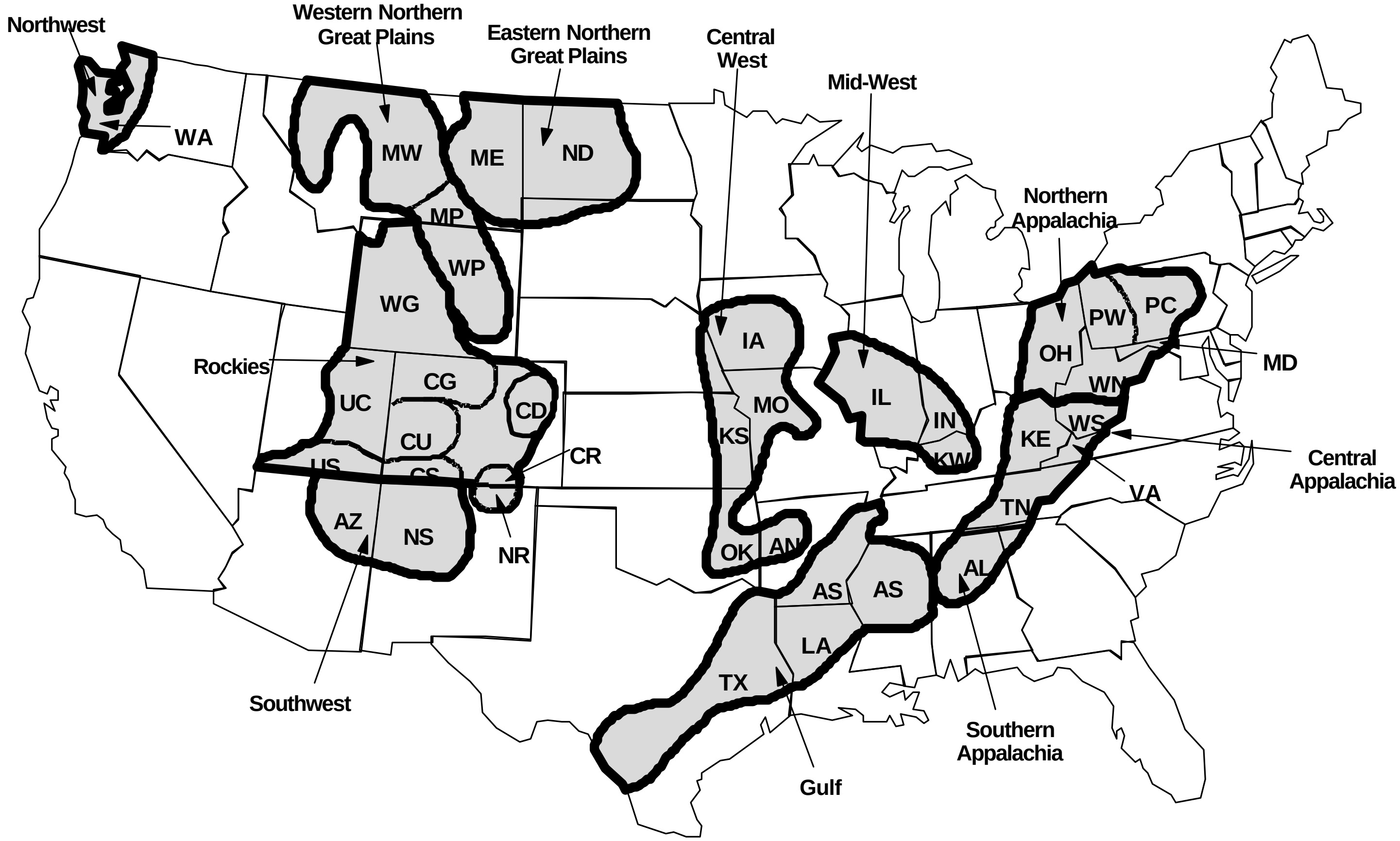
The EPA Base Case 2000 uses coal supply regions and coal demand regions connected by transportation links to model coal markets in IPM. Supply regions represent aggregations of coal-mining areas while the demand regions represent coal plants with similar supply infrastructures within the same geographic area. Transportation links connect the supply and demand regions. A demand region may have transportation links with more than one supply region.

Each coal supply region in the EPA Base Case 2000 contains similar coal-mining areas that supply one or more coal types. Coal supply regions may differ from one another in the types and quality of coal they can supply. Table 8.1 below lists the coal supply regions included in the EPA Base Case 2000. The supply regions are grouped into broad geographically based coal supply areas. Figure 8.1 provides a map showing both the coal supply regions and areas.

Table 8.1. Coal Supply Regions in the EPA Base Case 2000

Primarily High Sulfur Coal Reserves	High and Low Sulfur Coal Reserves
Northern Appalachia Pennsylvania, Central (PC) Pennsylvania, West (PW) Ohio (OH) Maryland (MD) West Virginia, North (WN) Midwest Illinois (IL) Indiana (IN) Kentucky, West (KW)	Gulf Texas (TX) Louisiana (LA) Arkansas South/Mississippi (AS) Central West Iowa (IA) Missouri (MO) Kansas (KS) Arkansas, North (AN) Oklahoma (OK)
Primarily Low Sulfur Coal Reserves	
Central Appalachia West Virginia, South (WS) Virginia (VA) Kentucky, East (KE) Tennessee (TN) Southern Appalachia Alabama (AL) Eastern Northern Great Plains North Dakota (ND) Montana, East Western Northern Great Plains Montana, Powder River (MP) Montana, West (MW) Wyoming, Powder River (WP)	Rockies Wyoming, Green River (WG) Colorado, Green River (CG) Colorado, Denver (CD) Colorado, Raton (CR) Colorado, Uinta (CU) Colorado, San Juan (CS) Utah, Central (UC) Utah, South (US) New Mexico, Raton (NR) Southwest New Mexico, San Juan (NS) Arizona (AZ) Northwest Washington (WA) Alaska Alaska (AK)

Figure 8.1. Map of the Coal Supply Regions in EPA Base Case 2000



The EPA Base Case 2000 retains the coal-supply curves and transportation cost assumptions used in the EPA Winter 1998 Base Case. These assumptions were based on the previously developed Coal Electric Utility Model (CEUM)[1]. There is a unique coal supply curve for each IPM coal supply region (shown in Table 8.1), coal type (shown in Table 8.5) within that region, and model run year. These supply curves describe the relationship between the coal supply and the mine-mouth price of coal. They capture how coal mine-mouth prices change with the quantities demanded. The coal supply curves take into account the coal resource base, supply costs and coal supply productivity. Table 8.2 lists the coal productivity assumptions (expressed in terms of annual percentage cost reductions) underlying the coal supply curves used in the EPA Base Case 2000.

Table 8.2. Annual Cost Reduction Assumptions in Coal Production

Years	Annual Percentage
2005 - 2009	2.4 %
2010 - 2025	2.1 %

Under these assumptions, the market price of coal in the EPA Base Case 2000 is determined endogenously in IPM: it is the price at which the supply of a specific type of coal from a specific coal supply region satisfies the demand in a specific model run year. The market price for coal is specific to each supply region and coal type combination, i.e. all plants purchasing the same coal type from a supply region face the same mine-mouth market-clearing price. Table 8.3 below summarizes the average mine-mouth market-clearing prices that resulted under EPA Base Case 2000. Prices are shown for coal supply areas in each model run year. They are averaged across the constituent coal supply regions (in Table 8.1) and coal types (in Table 8.5).

Table 8.3. Average Mine-Mouth Coal Prices in the EPA Base Case 2000 (1999$/Ton)

	2005	2010	2015	2020
Central and Southern Appalachia	$22.37	$20.20	$18.91	$17.15
Central West and Gulf	$10.60	$9.35	$8.39	$8.58
Midwest	$14.91	$13.14	$11.81	$10.63
Northern Appalachia	$18.24	$17.00	$15.50	$14.29
National Average	**$12.42**	**$11.24**	**$10.25**	**$9.45**

The mine-mouth market-clearing price does not include transportation costs incurred in moving the coal between the supply regions and demand regions. The EPA Base Case 2000 groups coal plants with similar supply infrastructure and within the same geographic area into coal demand region. Each transportation link between a coal demand and supply region is provided a transportation cost based on the distance and mode of transport for that link. The delivered coal price is the sum of the transportation costs and the mine-mouth market-clearing price. Table 8.4 below provides a summary of the national average mine-mouth coal price and delivered coal prices that resulted under the EPA Base Case 2000.

[1] Analyzing Electric Power Generation Under CAAA, March 1998, pp. A2-13 to A2-16.

Table 8.4. National Average Mine-Mouth and Delivered Coal Prices in the EPA Base Case 2000 (1999$/mmBtu)

	2005	2010	2015	2020
Mine-mouth Price (U.S. Average)	$0.59	$0.53	$0.48	$0.44
Delivered Price (U.S. Average)	$1.10	$1.00	$0.92	$0.84

8.1.2 Emission Factors

The EPA Base Case 2000 uses emission factors to represent the SO_2, CO_2 and mercury content of coal. The emission factors describe the ratio of the specific emission to the energy contained in the coal and represent the out-of-stack emissions that would occur if the fuel were combusted at a facility and no reductions occurred at the facility. The EPA Base Case 2000 retains the assumptions for the sulfur and carbon emission factors developed in the EPA Winter 1998 Base Case. As discussed in detail in section 5.3.1, the mercury emissions assumptions in EPA Base Case 2000 are based upon EPA's Information Collection Request that was completed in 2000.

Sulfur Dioxide

EPA Base Case 2000 uses 5 different sulfur grades of bituminous coal, 3 different grades of subbituminous coal, and 3 different grades of lignite to represent the emission factor for coal. The sulfur grades capture the variations in sulfur content of the different types of coal. Table 8.5 below lists the different sulfur grades used in the EPA Base Case 2000.

Table 8.5. SO_2 Emission Factors of Coal Used in the EPA Base Case 2000

Coal Grade Designation in the EPA Base Case 2000	Sulfur Dioxide (lbs./mmBtu)
Bituminous	
Low Sulfur Bituminous (Western) (BB)	1.0
Low Sulfur Bituminous (Eastern) (BA)	1.1
Low Medium Sulfur Bituminous (BD)	1.5
Medium Sulfur Bituminous (BE)	2.2
Medium High Sulfur Bituminous (BF)	3.0
High Sulfur Bituminous (BG)	5.0
Subbituminous	
Low Sulfur Subbituminous (SB)	1.0
Low Medium Sulfur Subbituminous (SD)	1.4
Medium Sulfur Subbituminous (SE)	2.1
Lignite	
Low Medium Sulfur Lignite (LD)	1.4
Medium Sulfur Lignite (LE)	2.1
Medium High Sulfur Lignite (LF)	2.9

The SO_2 emission factors shown in Table 8.5 are used in three ways. First, for model plants representing existing unscrubbed coal steam units, the emission factors are compared to the applicable unit-level regulatory SO_2 emission rates (discussed in section 3.9.1) to determine which coal grades the model plant is allowed to burn in order to remain within its unit-specific regulatory emission rate limit. Second, the removal rate for existing scrubbed units (i.e., those units which entered the modeling time horizon with pre-existing scrubbers) is calculated from the unit's historical emission rate as contained in the NEEDS data base and the emission factor (shown in Table 8.5) for the predominant coal grade burned at the unit. Third, for all model plants representing coal steam units — whether existing or new, unscrubbed or scrubbed — the SO_2 emission factors shown in Table 8.5 are used to determine SO_2 emissions. The emission factors are scaled proportionately for model plants representing existing unscrubbed coal steam units with average historical emission rates (derived from the NEEDS database) of 0.8 lbs/mmBtu or less. Whether the emission factors are scaled or used directly as shown in Table 8.5, SO_2 emissions are obtained by multiplying the total consumption of each coal type (on a heat content basis, i.e., in mmBtu) for the period covered (e.g., annual) by the associated emission factor (in lbs/mmBtu). The result is the uncontrolled mass emissions (in lbs or tons) from each fuel type. Summing across all fuel types yields the total uncontrolled mass SO_2 emissions. If the model plant has SO_2 controls, the applicable removal rate is applied to obtain the total SO_2 mass emissions after scrubbing. (The SO_2 removal rate for new units is shown in Table 3.17 and for retrofits of existing units in Table 5.1. The removal rate for existing scrubbed units is calculated as described above.) System-wide emissions on a tonnage basis is then obtained by summing SO_2 mass emissions from all model plants. A model plant's emission rate (in lbs/mmBtu) for a specific period (e.g., a year) is calculated by dividing its total SO_2 mass emissions by the total coal of all types consumed on a heat content basis (i.e., in mmBtu) in the period.

Nitrogen Oxides

NO_X emission rates do not vary with fuel but are dependent on the combustion properties in the generating unit. They are therefore not treated here but in sections 3.9.2, Table 3.17, section 5.2 and Appendix 5.2.

Carbon Dioxide

The emission factor for CO_2 describes the emissions of CO_2 per unit of energy in coal. It represents the amount of out-of-stack emission that would occur if the coal were combusted at a generating facility. Table 8.6 below summarizes the assumptions on the CO_2 emission factors for the three coal grades in EPA Base Case 2000.

Table 8.6. Carbon Dioxide Emission Factors in EPA Base Case 2000

Fuel	Carbon Dioxide (lbs/mmBtu)
Bituminous Coal	205.3
Subbituminous Coal	212.7
Lignite	215.4

Mercury

Section 5.3.1 contains a detailed description of the assumptions in EPA Base Case 2000 regarding the mercury content of coal. For each coal sulfur grade in the EPA Base Case 2000, there are 1-3 mercury emission factors that characterize the mercury content for that grade of coal. Table 8.7 below provides a summary of the mercury emission factors in the EPA Base Case 2000. Each supply region producing a specific coal grade is assigned one of the listed emission factors, i.e, the one that most closely reflects the mercury content of its coal. Section 5.3.1 describes the methodology that was used in developing the mercury emission factors shown in Table 8.7 from data obtained under EPA's 1998-2000 "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions."

Table 8.7. Mercury Emission Factors in the EPA Base Case 2000

Coal Type by Sulfur Grade	Mercury Emission Factors by Coal Sulfur Grades (lbs/TBtu)		
	Emission Factor #1	Emission Factor #2	Emission Factor #3
Low Sulfur Eastern Bituminous (BA)	3.69	5.17	--
Low Sulfur Western Bituminous (BB)	3.41	4.1	7.85
Low Medium Sulfur Bituminous (BD)	5.07	12.54	21.95
Medium Sulfur Bituminous (BE)	6.08	10.45	18.42
Medium High Sulfur Bituminous (BF)	6.83	11.09	18.69
High Sulfur Bituminous (BG)	8.04	17.43	28.73
Low Sulfur Subbituminous (SB)	4.55	6.48	--
Low Medium Sulfur Subbituminous	4.4	6.7	--
Medium Sulfur Subbituminous (SE)	5.53	10.71	--
Low Medium Sulfur Lignite (LD)	8.45	--	--
Medium High Sulfur Lignite (LF)	5.88	9.79	–

8.2 Natural Gas

The EPA Base Case 2000 uses supply curves to model the natural gas supply. The Gas System Analysis Model (GSAM), a detailed gas supply model, originally developed by ICF Consulting, Inc. for the U.S. Department of Energy, was used to derive the supply curves, which provide a price-quantity relationship for natural gas supply in the United States. The supply curves in EPA Base Case 2000 incorporate the impact on prices of demand for natural gas from the non-electric sector. A separate supply curve was developed for each model run year in the base case. Details about GSAM and the assumptions used for the analysis can be found in Appendix 8.1, which contains ICF Consulting=s paper on ANatural Gas Supply Curves for the EPA Base Case 2000@.

8.2.1 Market Structure

The natural gas supply curves in EPA Base Case 2000 specify annual prices at the Henry Hub[2]. The EPA Base Case 2000 includes explicit transportation and seasonal adders to reflect the cost of moving gas from the source to the plant and to account for the seasonality in gas prices. (See Tables A8.6 and A8.7 in Appendix 8.1.)

In the EPA Base Case 2000, plants using natural gas for electric generation face market clearing wellhead prices. This price is endogenously determined in IPM by equating demand and supply. In EPA Base Case 2000, market clearing price, transportation and seasonal cost adders all enter into the calculations of total expenditures on natural gas consumption for electric generation. Table 8.8 below provides a summary of the wellhead and national average delivered price resulting under EPA Base Case 2000.

[2]The Henry Hub is a gas pipeline junction in Louisiana, which interconnects with nine interstate and four intrastate pipelines and offers shippers access to pipelines that have markets in U.S. Gulf Coast, Southeast, Midwest, and Northeast regions. Due to the Hub=s strategic centralized location, the price of natural gas at the Henry Hub serves as the generally accepted reference point for U.S. natural gas trading.

Table 8.8. US Wellhead and National Average Delivered Natural Gas Prices in the EPA Base Case 2000 (1999 $/mmBtu)

Year	Wellhead Gas Price (at Henry Hub)	Delivered Gas Price
2005	2.55	2.77
2010	2.45	2.68
2015	2.45	2.67
2020	2.45	2.66

8.2.2 Emission Factors

The EPA Base Case 2000 includes emission factor assumptions for CO_2 and mercury in natural gas. The emission factors specify the out-of-stack emission that would result from combusting natural gas in electric generation facilities without any controls. For the emission factor of CO_2 in natural gas, the EPA Base Case 2000 retains the assumption used in the EPA Winter 1998 Base Case of 117 lbs/mmBtu. The EPA Base Case 2000 also includes the assumption that the emission factor of mercury in natural gas is 0.00014 lbs/Tbtu, based on an earlier EPA study.[3]

8.3 Fuel Oil

8.3.1 Supply Assumptions

Unlike coal, natural gas and biomass prices, which are derived endogenously in EPA Base Case 2000, fuel oil prices are stipulated exogenously. The residual fuel oil price assumptions used in EPA Base Case 2000 are derived from crude oil prices in EIA's Annual Energy Outlook (AEO) 2000. The AEO 2000 crude oil prices are reproduced in Table 8.9.

Table 8.9. AEO 2000 Crude Oil Prices*

Year	World Oil Price (1999$/bbl)
2005	20.8
2010	21.3
2015	21.9
2020	22.4

*From AEO 2000, Appendix A (Reference Case), Table 12: Petroleum Product Prices

8.3.2 Emission Factors

The emission factors for fuel oil describe the SO_2, CO_2 and mercury content per unit of energy in the fuel oil. In the EPA Base Case 2000, these factors represent the emissions that would occur if the fuel oil were combusted and no reduction occurred at the facility.

[3]Analysis of Emissions Reduction Options for the Electric Power Industry,@ Office of Air and Radiation, US EPA, March 1999.

Sulfur Dioxide
The EPA Base Case 2000 includes three different residual fuel oil grades. The three grades are differentiated based on their sulfur content. Expressed in terms of pounds of sulfur dioxide per mmBtu, the three grades of residual fuel oil are: 2.2, 1.5 and 0.3 lbs/mmBtu of SO_2.

Carbon Dioxide
EPA Base Case 2000 retains the EPA Winter 1998 Base Case assumption that the CO_2 emission factor of residual fuel oil, regardless of sulfur content, is 173.9 lbs/mmBtu.

Mercury
Based on an earlier US EPA analysis,[4] EPA Base Case 2000 includes the assumption that the mercury emission factor for residual fuel oil, regardless of sulfur content, is 0.48 lbs/TBtu.

8.4 Biomass

Biomass is offered as a fuel for existing dedicated biomass plants and potential biomass gasification combined cycle under the EPA Base Case 2000. In addition to these plants, it is also offered to all coal-fired power plants under policy cases that include the biomass co-firing options described above in section 5.4.2. Biomass fuel supply curves were developed for EPA Base Case 2000 from the biomass fuel supply and price data in EIA's AEO 2001.

8.4.1 Market Structure

Consistent with the biomass fuel data and structure in EIA's AEO 2001, EPA Base Case 2000 utilizes thirteen regional biomass fuel supply curves, one for each of the 13 National Energy Modeling System (NEMS) regions represented in AEO 2001. Plants demand biomass from the supply curve corresponding to the NEMS region in which they are located. No inter-regional trading of biomass occurs. Each biomass supply curve depicts the price-quantity relationship for biomass and varies over time. There is a separate curve for each model run year. The supply component of the curve represents the aggregate supply in a region of four types of biomass fuels: forestry residue, agricultural residue, urban wood waste and mill residue and energy crops. The price component of the curve includes transportation cost and represents delivered fuel cost at the plant gate. The original AEO 2001 supply curves contained 50 price steps. For computational efficiency, this has been reduced to 8 or 9 prices steps (depending on region) in the biomass supply curves used in EPA Base Case 2000. Appendix 8.2 contains a table which provides a consolidated summary of the 2010 base case biomass supply curves for the 13 regions.

Biomass prices in EPA Base Case 2000 are derived endogenously based on the aggregate demand for biomass in each region. They represent market-clearing prices. There is a unique market-clearing price for each supply region and all plants using biomass from that supply region face the same market-clearing price.

8.4.2 Emission Factors

The EPA Base Case 2000 models SO_2 and mercury emissions from biomass combustion using biomass emission factors. The combustion of biomass fuel is considered to have a net zero impact on atmospheric carbon dioxide levels since the emissions released are equivalent in carbon content to the carbon absorbed during fuel crop growth.[5]

[4]Analysis of Emissions Reduction Options for the Electric Power Industry, Office of Air and Radiation, US EPA, March 1999.
[5] Hughes, E., ARole of Renewables in Greenhouse Gas Reduction,@ Electric Power Research Institute (EPRI): November, 1998. Report TR-111883, p. 28.

Sulfur Dioxide
The biomass SO_2 emission factor in EPA Base Case 2000 is 0.08 lbs/mmBtu[6].

Mercury
Based on an earlier EPA analysis, the EPA Base Case 2000 includes the assumption that mercury emission factor of wood waste is 0.57 lbs/Tbtu.[7]

8.5 Nuclear Fuel

EPA Base Case uses the AEO 2000 nuclear fuel price (1999$) forecast of $0.41/mmBtu for the 2005-2020 modeling horizon.

[6] Biomass Co-firing@, Chapter 2 in "Renewable Energy Technology Characterizations", U.S. Department of Energy and Electric Power Research Institute (EPRI), 1997.
[7] Analysis of Emissions Reduction Option for the Electric Power Industry,@ Office of Air and Radiation, US EPA, March 1999.